Ameren Exhibit 1.0 (Rev.)

ILLINOIS COMMERCE COMMISSION

DOCKET NO. 13-0115

REVISED DIRECT TESTIMONY

OF

JAMES L. VERHAAR

Submitted On Behalf Of

AMEREN ILLINOIS COMPANY

d/b/a Ameren Illinois

APRIL 3, 2013

TABLE OF CONTENTS

Page No.

ILLINOIS COMMERCE COMMISSION

DOCKET NO. 13-0115

REVISED DIRECT TESTIMONY OF

JAMES L. VERHAAR

Submitted On Behalf Of Ameren Illinois Company

I. INTRODUCTION AND WITNESS QUALIFICATIONS

Q. **Please state your name, business address and present position.**

A. James L. Verhaar, One Ameren Plaza, St. Louis, Missouri 63166. I am employed by Ameren Services Company ("Ameren Services" or "AMS") as a Consulting Engineer – Transmission Planning in the Transmission Policy and Planning Department. Ameren Services provides engineering support and other services for Ameren Illinois Company ("AIC" or the "Petitioner").

Q. **Please summarize your educational background and professional experience.**

A. A summary of my educational background and professional experience is attached as an Appendix to my testimony.

Q. **What are your duties and responsibilities in your present position?**

A. My responsibilities include performing various studies regarding the performance and reliable expansion of Ameren utility and interregional transmission systems, the conceptual design of supplies to major customers, the analysis of new generator interconnections, and the adequacy of system reactive supply. These responsibilities encompass transmission facilities owned by AIC.

II. PURPOSE AND SCOPE

Q. **Are you familiar with the Project proposed in the Petition filed by AIC in this proceeding?**

A. Yes. AIC is seeking a Certificate of Public Convenience and Necessity ("Certificate") authorizing it to construct a 345 kV electric transmission line (the "Transmission Line") in an area west of Peoria, Illinois, connecting the existing Fargo Substation and Duck Creek-Tazewell transmission line. A proposed new 345 kV switching station north of Mapleton, Illinois (the "Mapleridge Substation") and substation modifications at the Fargo Substation (which, together with the Transmission Line, constitute the "Project") will also be required.

Q. **Is AIC seeking expedited approval of the Certificate?**

A. Yes. Section 8-406.1 of the Public Utilities Act [220 ILCS 5/8-406.1] allows a utility to apply for a Certificate of Public Convenience and Necessity for a new high voltage electric transmission line under an expedited procedure.

Q. **Has AIC complied with all the provisions of Section 8-406.1 requiring additional information to support this Petition?**

A. Yes. Subsections 8-406.1(a), (d), and (e) contain information requirements a utility must include in its application or publish in an official State newspaper or on a dedicated Internet website. I have attached a checklist to facilitate verification that AIC has provided all the required information under Section 8-406.1 as Ameren Exhibit 1.1. As Ameren Exhibit 1.1 shows, the information required under Section 8-06.1 has been provided in the Petition, direct testimony and exhibits submitted by AIC.

Q. **What is the purpose of your testimony in support of this Petition?**

A. The purpose of my testimony is to provide an overview of the present and future electric service needs in the Project area, and to explain the planning undertaken to meet those needs. My testimony will cover two general topics. First, I will discuss the design and planning of AIC's electric transmission and delivery system. Second, I will explain why the project is necessary, including a description of the existing supply to the area, the system reinforcement needs of the area, AIC's plan to meet those needs with a new 345 kV electric line, a new 345 kV switching station, as well as for substation modifications at the Fargo Substation, and the alternatives considered.

Q. **Please summarize why this project is necessary to provide adequate and reliable service.**

A. This project is needed to prevent loss of service to the Peoria area due to the coincident outage of two transmission elements. The amount of load at risk is approximately 1600 MW. This amount exceeds the 300 MW threshold prescribed by AIC's transmission planning criteria filed with FERC and thus requires mitigation. In addition, this project provides mitigation for transmission elements with thermal overloads due to the coincident outage of two transmission elements.

Q. **In addition to your testimony are you sponsoring any other exhibits?**

A. Yes. In addition to Ameren Exhibit 1.0, I am sponsoring the following:

- Ameren Exhibit 1.1 Statutory Requirements Checklist.
- Ameren Exhibit 1.2 One-line diagram - existing transmission and substransmission 138 kV Peoria area.

- Ameren Exhibit 1.3 — One-line diagram - existing transmission and substransmission 69 kV Peoria area.
- Ameren Exhibit 1.4 — One-line diagram – proposed transmission plan.
- Ameren Exhibit 1.5 — One-line diagram – proposed transmission plan.
- Ameren Exhibit 1.6 — NERC Standard TPL-003-0.
- Ameren Exhibit 1.7 — Ameren Transmission Planning Criteria and Guidelines.
- Ameren Exhibit 1.8 — Peoria area historical and projected load forecast.
- Ameren Exhibit 1.9 — Summary of alternatives investigated for expansion of the Peoria area transmission supply.
- Ameren Exhibit 1.10 — MTEP 09 Appendix A1.
- Ameren Exhibit 1.11 — Chronological listing of correspondence between Ameren and the MISO relevant to the Fargo-Mapleridge 345 kV line project.
- Ameren Exhibit 1.12 — Powerflow diagram – expected 2016 summer powerflow results with all existing transmission facilities in service.
- Ameren Exhibit 1.13 — Powerflow diagram – 2016 summer powerflow results producing unacceptable AIC system performance: outage of Edwards units 2 and 3.
- Ameren Exhibit 1.14 — Powerflow diagram – 2016 summer powerflow results producing unacceptable AIC system performance: outage of two Tazewell 345-138 kV transformers.
- Ameren Exhibit 1.15 — Powerflow diagram – 2016 summer powerflow results producing unacceptable AIC system performance: outage of Edwards unit 3 and one Tazewell 345-138 kV transformer.
- Ameren Exhibit 1.16 — Powerflow diagram – expected 2016 summer powerflow results with all existing and proposed transmission facilities in service

- Ameren Exhibit 1.17 — Powerflow diagram – summer 2016 peak load levels problem resolved with Project: outage of Edwards units 2 and 3.
- Ameren Exhibit 1.18 — Powerflow diagram – summer 2016 peak load levels problem resolved with Project: outage of two Tazewell 345-138 kV transformers.
- Ameren Exhibit 1.19 — Powerflow diagram – summer 2016 peak load levels problem resolved with Project: outage of Edwards unit 3 and one Tazewell 345-138 kV transformer.
- Ameren Exhibit 1.20 — Powerflow diagram – expected 2016 summer powerflow results with all existing facilities in service with New Peoria Area Substation Alternative.
- Ameren Exhibit 1.21 — Powerflow diagram – summer 2016 peak load levels problem resolved with New Peoria Area Substation Alternative: outage of Edwards units 2 and 3.
- Ameren Exhibit 1.22 — Powerflow diagram – summer 2016 peak load levels problem resolved with New Peoria Area Substation Alternative: outage of two Tazewell 345-138 kV transformers.
- Ameren Exhibit 1.23 — Powerflow diagram – summer 2016 peak load levels problem resolved with New Peoria Area Substation Alternative: outage of Edwards unit 3 and one Tazewell 345-138 kV transformer.
- Ameren Exhibit 1.24 — Powerflow diagram – expected 2016 summer powerflow results with all existing facilities in service with new Richland Substation Alternative.
- Ameren Exhibit 1.25 — Powerflow diagram – summer 2016 peak load levels problem resolved with New Richland Substation Alternative: outage of Edwards units 2 and 3.
- Ameren Exhibit 1.26 — Powerflow diagram – summer 2016 peak load levels problem resolved with New Richland

Substation Alternative: outage of two Tazewell 345-138 kV transformers.

- Ameren Exhibit 1.27 — Powerflow diagram – summer 2016 peak load levels problem resolved with New Richland Substation Alternative: outage of Edwards unit 3 and one Tazewell 345-138 kV transformer.

III. <u>ELECTRIC SYSTEM DESCRIPTION AND PLANNING</u>

Q. **Please explain how AIC's transmission and distribution system delivers electricity to customers.**

A. AIC considers its electric system as being comprised of three functional levels for planning and operating purposes: (1) transmission (345 kV, 230 kV, 161 kV and 138 kV); (2) sub-transmission (69 kV and 34.5 kV); and (3) distribution (12 kV and 4 kV). Each of these systems has unique design and operating characteristics. The transmission system is a network of higher voltage lines that are used to move electric energy from the generation sources to the distribution systems and to move electric energy between utility systems. A limited number of very large customers are served directly from the transmission system. The sub-transmission system includes both network and radial 69 kV and 34.5 kV lines. Bulk supply transformers supply electricity from the transmission system to the sub-transmission system, which in turn delivers power at the intermediate voltage levels to distribution substations or directly to large customers. Distribution substation transformers step the sub-transmission voltages down to the 12 kV and 4 kV distribution system voltages. The distribution system is predominantly configured as a radial system.

Q. **Please explain the two major transmission system voltages in AIC’s service territory.**

A. The two transmission voltages most often utilized in AIC's system are 345 kV and 138 kV. The 345 kV network is the backbone of AIC's transmission system and is the most common high voltage network in the Midwestern United States, where it is used for major transmission interconnections. The 345 kV network connects to large base load power plants and is designed to move large quantities of power from these plants to major load centers and to neighboring power systems. The 138 kV network is more of a local transmission system as it connects to smaller power plants and moves the power from these plants and the 345 kV network to the bulk distribution substations and customer substations within the major load centers.

Q. **What factors must be considered in developing, operating and maintaining an adequate, efficient, and reliable transmission (and sub-transmission) system?**

A. The transmission, sub-transmission and distribution systems are planned and designed to supply all loads during a wide variety of conditions, ranging from peak to minimum load. AIC, through Ameren Services, follows established planning criteria (NERC Standards TPL-002-1b and TPL-003-0 as well as Ameren's Transmission Planning Criteria and Guidelines) which are applied to ensure the development of a system which will adequately and reliably serve the projected customer loads as well as meet its obligations to its transmission service customers, as part of the interconnected transmission system.

The transmission system is planned to supply all loads and transmission services without violating loading and voltage limits during normal and single contingency outage conditions. The system is planned to allow operation with an outage of any single generating unit or transmission facility. In addition, with any one generator out of service, the system is planned to operate with all equipment loaded at or below its emergency ratings and with voltages within acceptable limits for the loss of any one transmission facility.

The transmission system is also evaluated under conditions where there is a current outage of any two transmission elements. AIC's transmission planning criteria parses the loss of customer load for the concurrent outage of any two transmission elements (NERC TPL-003-0 contingency events) into two categories. In the first category, load is shed in a controlled manner via automatic or operator initiated actions to keep the loadings and system voltages within established limits. In the second category, the supply to a defined pocket of load is lost as a direct consequence of the system topology and/or natural response of the system. For the first category, the AIC planning criteria requires mitigation if the amount of load to be shed in a controlled manner exceeds 100 MW. For the second category, the AIC planning criteria requires mitigation if the amount of load exposed to being dropped for more than 15 minutes due to the system topology and/or the natural response of the system exceeds 300 MW.

The sub-transmission system is likewise planned to supply all load at peak load conditions, and the performance of the system is evaluated for single contingency outage conditions. Load supplied by a radial line will be dropped during outages of that line. If load has to be dropped or left out-of-service as the result of a contingency on the sub-transmission system, system improvement projects are considered that would minimize future risk of load being out-of-service.

In all cases, the system is planned, designed and operated to maintain adequate voltage to the customers. The system is also planned to avoid thermal overload of equipment and minimize the likelihood of catastrophic equipment failure and widespread service outages. The higher voltage lines have greater load carrying capability than the lower voltage lines, and the higher voltage lines can deliver power over greater distances more efficiently, with less energy loss and less voltage drop, than lower voltage lines. As a result, extending transmission facilities close to the load minimizes energy losses and improves the delivery voltage.

Q. **Why do you study contingency conditions as well as normal operating conditions?**

A. Planning for contingencies recognizes that system disturbances and equipment failures are inevitable. The effects of these contingency conditions on the system must be evaluated and considered when determining the need for system reinforcement and the specific reinforcement plans. The goal is to provide reliable electric service at a reasonable cost. Contingency planning is commonly used throughout the electric utility industry. Contingency planning has historically provided acceptable reliability at a reasonable cost. In addition, NERC reliability standards require that the bulk electric system be planned so as to be able to withstand certain contingency events.

Q. **Please explain how you determine that a plan has the capacity to meet the projected demand for electricity while providing adequate voltage to the customers.**

A. An engineering analysis is performed to verify that a plan can meet the projected demand for electricity within the capability of the facilities while providing adequate voltage to the customers. In a typical planning study, the analysis utilizes computer software that evaluates the operation of the system under normal system conditions with all components in service, and under contingency conditions. The electric load on each component is evaluated relative to its thermal rating to ensure there are no overloads under the assumed study conditions. System voltages are also examined to ensure adequate voltage levels are maintained.

Q. **Please outline the voltage criteria used to identify low voltage conditions.**

A. The voltage criteria used by AIC system planning has been developed to provide voltages to the customer consistent with the Standards of Service for Electric Utilities in 83 Illinois Administrative Code Part 410. The distribution system planning criteria sets maximum and minimum steady state voltage limit guidelines at the low voltage bus of distribution and customer substations and at 34.5 kV and above customer delivery points for normal and contingency outage conditions. Voltages below these thresholds are investigated to ensure adequate voltage will be maintained on the distribution feeders. Transmission system voltage below 95% of nominal has been established as an indication of a possible deficiency, considering the voltage requirements for the subtransmission and distribution systems. Voltages below this threshold would initiate discussion with the distribution system planner to ensure that adequate distribution voltages would be provided for normal and single contingency conditions. For conditions beyond single contingencies, transmission voltages below 90% of nominal would be investigated further to determine what actions, if any, are required so that the contingencies would not result in widespread outages. These investigations would consider the voltage impact of line faults before the load tap changing transformers could respond. It should be noted that 85% is the level at which a voltage collapse is essentially assured. Conditions which result in 86% - 89% voltages in the steady-state analysis carry significant risk for voltage collapse.

Q. **Does AIC regularly assess the adequacy of existing facilities to transmit and distribute power to customers?**

A. Yes. Ameren Services, as the agent for AIC, regularly evaluates projected system conditions relative to the Ameren Transmission Planning Criteria (attached as Ameren Exhibit 1.7) to ensure that the performance of AIC's transmission system meets the NERC planning standards. Assessments of the transmission system are performed annually to meet the NERC standards based on the latest available system and substation load forecast information, generation capacity and control information, transmission network impedance topology, and interchange assumptions. The assessments seek to identify projected transmission facility overloads and voltages outside of established limits during both normal and contingency conditions. Corrective plans are then developed to ensure that AIC's transmission system performance meets the performance requirements of the standards.

The results of these various assessments provide an indication of when, and to what extent, system reinforcement is needed. Projected deficiencies in transmission system performance qualify for system reinforcement and the assessments and corrective plans provide the basis for transmission system upgrades to be included in the construction budgets of AIC.

Q. **What actions are taken based upon such an assessment?**

A. When projected concerns are identified, a detailed system study is initiated to determine and evaluate alternatives and develop a recommended plan.

Q. **What is the time frame over which transmission plans are studied?**

A. Transmission plans typically cover a time period of up to ten years into the future and include a detailed five-year construction plan and a year 6 through 10 planning horizon strategy. Longer-range transmission projects have also been identified which help to guide system development.

Q. **Why is transmission planning conducted on a planning horizon of up to 10 years?**

A. Major transmission and other electric service infrastructure projects have a construction lead time of several years. AIC typically estimates that transmission projects will require 5 to 5.5 years for study, regulatory approval, design, right-of-way easement requisition, environmental studies, application for and receipt of permits, and construction. As a result, transmission planning must look at projected loads several years into the future, and, based on those projected loads, determine where transmission or other infrastructure projects are needed, in order to allow sufficient time for planning and construction of new facilities. Put another way, AIC cannot determine in year 1 that an area will experience voltage collapse in year 2 and then construct the needed facilities by year 2 to allow continued provision of adequate and reliable service – longer planning horizons are required.

IV. THE NEED FOR THE PROJECT

Q. Please describe the facilities that currently provide electric service to the Project area west of Peoria, Illinois.

A. The load in the Peoria area is approximately 1600 MW. The Peoria area is primarily supplied by a network of 138 kV transmission lines from the Tazewell Substation and Edwards Generating Station. The Peoria area is completely dependent on the supplies from these two stations. The Tazewell Substation has three 345 kV supply connections (a line from Duck Creek Generating Station, a line from the ComEd Powerton Generating Station and a line from the ComEd Kendal County Substation), six 345 kV breakers, two 345-138 kV transformers, six outlet 138 kV lines and one 138-69 kV transformer. In addition, the Edwards Generating Station has one 360 MW generator connected to the 138 kV bus, one 275 MW generator connected to the 69 kV bus, one 125 MW generator connected to the 69 kV bus and eight 138 kV outlet lines. Ameren Exhibit 1.12 shows the Peoria area transmission system with all transmission facilities in service, including the bus voltages, the line flows and the transformer flows.

Q. How long has it been since the Project area had a major electrical upgrade?

A. The last major facility addition in the Peoria area was the Tazewell Substation which was placed in service in 1975. The Duck Creek Generating Station was placed in service in 1974.

Q. Is load expected to increase in the Peoria area?

A. Yes. The latest available load forecast for the Peoria area, in addition to historical area loads for 2011 and 2012, is attached as Ameren Exhibit 1.8. The load forecast in the

Peoria area is shown to increase between 1% to 1.8 % per year. The current Peoria area load projection is 1720 MW in summer 2016. This information shows the contribution to total area load from AIC distribution substations, large customer loads, Rural Electrification Administration (REA) and other utility substation load. As can be seen, no growth in large customer load has been assumed in arriving at a total load projection for the Peoria area. Because of the distances involved, load transfers from the Peoria area to other areas of AIC's system are not feasible. Attempting to transfer customer loads over such distances would likely result in unacceptably low voltage at those customer loads.

Q. **How was this load forecast developed?**

A. Ameren's Distribution System Planning Department provides load projections for each distribution and customer substation that connects to the subtransmission system. These load projections are incorporated into powerflow models, which are then utilized to perform system studies to assess system adequacy.

Q. **Has AIC assessed the electrical supply system serving the Peoria area?**

A. Yes. AIC reviews the need for system upgrades or operational solutions throughout its service area, including in the Peoria area, on an annual basis. These reviews have followed the planning and assessment process discussed above. Study work specific to the Peoria area involved an evaluation of various alternatives for expanding transmission supply to the Peoria area. Recent studies have been conducted to review the impacts of new load being added in the Peoria area. The power flow base case used as a starting point for this most recent analysis consists of a NERC Multi-Regional Modeling Working Group (MMWG) 2010 series 2016 summer case. This power flow model represents most of the transmission system in the Eastern US Interconnection. It uses summer ratings for the existing units that are dispatched to serve loads based on a 50/50 forecast of summer 2016 peak conditions. Detailed models for bulk supply transformers connected directly to the transmission system with a detailed representation of the Peoria 69 kV system are included. The 69-12 kV substation loads are modeled on the 69 kV bus, with capacitor banks modeled explicitly. Peoria area loads were adjusted to reflect a 90/10 forecast of summer 2016 peak conditions.

Q. **Please summarize the results of this study process.**

A. The analysis concluded that the Transmission Line is required to ensure adequate and reliable service to the Project Area. As described above, the transmission system in the Peoria area is heavily dependent on one substation and one generating station located on the south end of the region. The Peoria area may be viewed as a single pocket of load with primary supplies from the Tazewell 345-138 kV Substation and the Edwards Generating Station. It is expected that by summer 2016, the Peoria regional area could experience voltage collapse from the loss of two bulk electric system elements. This exposure includes the coincident outage of Edwards units 2 and 3 or the coincident outage of the two Tazewell 345-138 kV transformers. The total amount of load that would experience a loss of supply for these situations is approximately 1600 MW. A simulation of 2016 summer peak load conditions showed multiple busses in the Peoria area fall below 90%, with voltages as low as 86.15% immediately following an outage of Edwards units 2 and 3. An additional simulation, with loads adjusted to 97% of expected peak values to permit convergence of the powerflow solution, showed bus voltages in the Peoria area were as low as 89.28% immediately following an outage to the two Tazewell transformers. Under this contingency, eight 138 kV branches in the area exceeded their thermal limit with overloads as high as 134.5%, thus adding to the threat of voltage collapse as these lines trip out due to thermal overload.

Further analysis has shown that the coincident outage of Edwards unit 3 and one of the Tazewell 345-138 kV transformers will result in the thermal overload of the remaining Tazewell 345-138 kV transformer. The loading of the remaining transformer is above 700 MVA, which is the size of the largest transformer at this voltage level on the Ameren system. This is a violation of Ameren criteria which states that a line + generator violation is treated as a NERC Category B violation, which requires mitigation. The result of this thermal overload means that additional 345-138 kV transformation is required in the area.

Q. **Is system reinforcement needed for the Project area?**

A. Yes. Reinforcement is required to address the low voltages in the Peoria area, meet the need for additional 345-138 kV transformation for the aforementioned NERC Category C contingencies as found in Exhibits 1.13 – 1.14, and eliminate the projected exposure to loss of load. As discussed above, a simulation of 2016 summer peak load conditions showed that immediately following an outage of Edwards generating units 2 and 3 (a NERC Category C3 event as defined in Reliability Standard TPL-003-0), some voltages in the Peoria area would fall below 90% of nominal. In addition, a simulation of the loss of the two Tazewell 345-138 kV transformers (also a NERC Category C3 event) showed voltages as low as 89.28%, with numerous thermal loading violations ranging from 108% to 135% of emergency rating. It is likely that one or more of these heavily-loaded facilities would subsequently trip offline, making voltage collapse more likely and accelerating loss of service to the majority of the customer load in the Peoria area.

Finally, a simulation of the loss of one of the Tazewell 345-138 kV transformer combined with the loss of Edwards generating unit 3 (an additional Category C3 event) would result in the thermal overload of the remaining Tazewell 345-138 kV transformer, with a loading greater than the largest transformer unit at this voltage level found on the Ameren system. These situations are depicted in Ameren Exhibits 1.13 – 1.15.

Q. **How does AIC propose to address these concerns?**

A. AIC proposes to address the concerns discussed above by construction of the 345 kV transmission line, the new 345 kV switching station (the Mapleridge Substation) and the installation of 345 kV terminal equipment and 345-138 kV transformation at the Fargo Substation. AIC has concluded this represents the best and least cost means of providing the required system reinforcement. Other alternatives considered are shown in Ameren Exhibit 1.9 and discussed below.

Q. **How will the addition of the new 345 kV line improve the reliability of the electric system in the Project Area?**

A. With the addition of the new Mapleridge 345 kV substation on the Duck Creek-Tazewell line, the addition of 345 kV equipment and a 345-138 kV transformer at the existing Fargo Substation, and the installation of the 345 kV Transmission Line between Mapleridge and Fargo Substations, the post-contingency loading and voltage issues associated with the three Category C events described above would be resolved. Following the addition of these system improvements, transmission voltages would be greater than 96% for all busses immediately following the outage of Edwards units 2 and 3, with no thermal overloads on the transmission system. In addition, no transmission voltages would be less than 98% immediately following the loss of both Tazewell 345-138 kV transformers with no thermal overloads on the transmission system. Finally, no thermal overloads on the transmission system or transmission voltages less than 97% occur with the coincident outage of Edwards unit 3 and one of the two Tazewell 345-138 kV transformers. (See Ameren Exhibits 1.17 – 1.19.) Thus the Transmission Line would improve voltages, improve reliability of service, and also add capacity for future load growth in the Peoria area. The Project would ensure continued reliable service to customers within the Peoria area and effectively satisfy NERC Reliability Standard TPL-003-0 and Ameren Transmission Planning Criteria.

Q. **Please describe MISO's role in the determination of the need for the Transmission Line.**

A. Ameren provides information to MISO periodically regarding Ameren's plans for upgrades and additions to Ameren's transmission system. This effort includes an annual list of Ameren's plans for upgrades and additions. Also, as part of compliance with FERC Order 890, MISO and the Transmission Owners in MISO hold Sub-regional Planning Meetings multiple times each year. Information on planned upgrades and additions to the transmission system is presented at these meetings. Ameren provides information to MISO to be presented at these meetings on each planned project. The information is compiled in the form of PowerPoint slides.

Q. **Were there communications between AIC and MISO?**

A. Yes. Material communications between Ameren and MISO regarding this project are shown in chronological order in Ameren Exhibit 1.11. Please note that, while this project appears in MISO's project list, Ameren Services identified the need for this project.

Q. **Does MISO allow cost sharing for the Project?**

A. This project was classified as a baseline reliability project in MISO's MTEP09 (MISO Transmission Expansion Plant 2009) study and is therefore eligible for cost sharing under the provisions of the MISO Attachment FF. In MISO's MTEP09 study, this project was listed in MISO's Appendix A. Appendix A contains the transmission expansion plan projects that are approved by MISO's Board of Directors. In the cost allocation information referenced in Ameren Exhibit 1.10, the AMIL load zone would bear approximately 84% of the cost for this project. (With respect to the MISO tariff, 345 kV baseline reliability projects are to be cost shared among MISO members as follows: 20% allocated across all MISO pricing zones based on load ratio share and the remaining 80% allocated sub-regionally based on Line Outage Distribution Factors.) The installation of the 345 kV to 138 kV transformer is considered a 138 kV reliability project which is allocated 100% sub-regionally under MISO Attachment FF. While Attachment FF provides the cost allocation guidelines for this project, the revenue will be collected under MISO Schedule 26. This new line would not be considered a "merchant line" by MISO.

Q. **Please summarize the planning parameters of the new line.**

A. The new transmission line will be designed and operated at 345 kV. The long-term emergency current carrying capability of the line will be 3000 A.

Q. **Did AIC consider alternatives to the Project and construction of the Transmission Line?**

A. Yes. AIC considered two alternative projects to address the system concerns I discuss above. The two alternatives considered were:

- Install a new 345 kV breaker position at Tazewell Substation. Extend a 345 kV line from Tazewell Substation to Richland Switching Station. Install a new 345 kV and 138 kV substation at Richland. Install a 345-138 kV 560 MVA transformer at Richland Substation. Approximately 30 miles of new 345 kV transmission line would be required. The estimated cost of this alternative project is $97,500,000.

- Install a new 345 kV breaker position at Tazewell Substation. Extend a 345 kV line from Tazewell Substation to a new substation located where the existing double circuit lines 1357 and 1344 split. Install a new 345 kV and 138 kV substation at this location. Install a 345-138 kV 560 MVA transformer at this new location. Approximately 23.5 miles of new 345 kV transmission line would be required. The estimated cost of this alternative project is $86,300,000.

Further details of these alternatives are outlined in Ameren Exhibit 1.9. Power flow results found in Exhibits 1.20 – 1.27 show the effect of the alternative projects on the contingency scenarios detailed above.

Q. **What did AIC conclude as the result of evaluating these alternatives?**

A. The first alternative was rejected because it was the most expensive of the three alternatives and required additional upgrades on the 138 kV system. The second alternative was rejected because it was more expensive than the alternative chosen and did not provide the opportunity to expand the 345 kV network in the future in order to tie into existing 345 kV facilities near the Peoria area. As indicated in Ameren Exhibit 1.9, AIC concluded that AIC's chosen project alternative significantly improves the robustness of the transmission system in the area, eliminates the projected exposure to voltage collapse from double contingency scenarios, can be constructed in the shortest amount of time, and is the least cost option (approximately $62.6 million as explained by witness Mr. Adam Molitor). I would note that these alternatives represent project alternatives, which are separate and distinct from the routing alternatives discussed by AIC witnesses Mr. Molitor and Ms. Donell Murphy.

Q. **Was demand side management considered?**

A. AIC presently employs a number of incentives at both the residential and commercial level to encourage energy efficiency. Reductions in load as a result of these incentives have already been included in the distribution load projections, which in turn have been used as the basis for powerflow simulations of system conditions made which indicate the need for the proposed transmission project.

Q. **Were reactive supply additions considered?**

A. The possibility of installing distribution capacitors and static var compensators was considered. This possibility was rejected for several reasons. First, it was determined that this approach would cost over $12 million just to prevent voltage collapse in the area, but would leave a significant number of 138 kV busses with voltage levels less than 95% of nominal. Second, this would not address the need for additional 345-138 kV transformation in the area or the numerous line overloads on the system. Third, it would not add robustness to the overall supply to the area and would carry a high maintenance cost. Ultimately, reactive supply additions would only defer the need to build the Transmission Line.

Q. **Was a Present Value of Revenue Requirements comparison performed for these alternatives?**

A. No. A Present Value of Revenue Requirements comparison was not completed for the alternatives because the in-service date for each of the alternative transmission projects would be essentially the same. Therefore, a comparison of the costs between the various alternatives was done based on comparing capital costs. It is not envisioned that any events would occur that would cause a different alternative to become more economical than the alternative selected.

Q. **What did AIC conclude regarding system improvements in the Project area?**

A. System reinforcements are necessary, due to the potential impact with Edwards generating units 2 and 3 out of service, the coincident outage of two 345-138 kV transformers at Tazewell or the coincident outage of Edwards unit 3 and one of the 345-138 kV transformers at Tazewell. Power flow simulations indicate that transmission facility overloading will occur with any of the contingency events discussed and voltage collapse would occur with Edwards units 2 and 3 out of service or with the loss of both Tazewell transformers. Under the voltage collapse scenarios, loads significantly in excess of 300 MW would be dropped. The Ameren Transmission Planning Criteria require system reinforcements if the amount of load exposed to being dropped for more than 15 minutes due to the system topology and/or the natural response of the system exceeds 300 MW.

While there are other project alternatives that would address the critical system needs, the alternative which should be pursued is the construction of a 345 kV switching station (the Mapleridge Substation), the construction of the Transmission Line between the Fargo and Mapleridge Substations, and the addition of 345 kV equipment and a 345-138 kV transformer at the Fargo Substation. This project alternative is the least cost option and significantly improves the robustness of the transmission system in the Peoria area, improves voltages in the rapidly growing area of northwest Peoria and eliminates the projected exposure to voltage collapse and thermal overloads due to double contingency scenarios.

Q. **Are there other 345 kV transmission projects planned in the general project area over next five years?**

A. Yes. A 345 kV transmission line is planned for Fargo to Galesburg to Oak Grove, to be in service in 2016 (Oak Grove-Galesburg) and 2018 (Galesburg-Fargo). This transmission line is one of the components of the MISO Multi Value Projects (MVP), which provide the benefits as described in the MISO MVP Analysis and Report.

Q. **What is the relationship between the Fargo to Oak Grove project and the Fargo-Mapleridge project?**

A. Fargo-Mapleridge was developed as a stand-alone reliability project to provide the best and least cost, method of resolving certain reliability issues in the Peoria area, as I discuss above. Since this project was approved by MISO in MTEP09, it has been included in all MISO studies related to the MVP projects. Thus, a base assumption of the MVP analysis, including the determination of the need for Fargo to Oak Grove, is that Fargo-Mapleridge is in service. If Fargo–Mapleridge were not put into service, the MISO MVP analysis would have to be re-done for this part of the portfolio.

Q. **Has AIC studied the impact of constructing Fargo-Oak Grove as a stand-alone project to address the reliability needs in the Project area?**

A. No. However, AIC expects that, if Fargo-Oak Grove was studied as an alternative to Fargo-Mapleridge for addressing reliability needs in the Project area, it would be rejected for at least two reasons. First, its cost would be significantly greater due to the route length. Second, it would depend on construction of certain facilities by a foreign utility, Mid-American Energy Company.

Q. **Was Fargo-Oak Grove discussed during the public meeting process?**

A. Yes.

Q. **Will any existing facilities be removed and not utilized after the installation of the proposed line?**

A. There are no plans to retire or remove any existing facilities after installation of the proposed facilities.

Q. **What is the timeframe for completion of the Transmission Line?**

A. The anticipated in-service date is December 1, 2016. This date was determined by AIC as an outcome of powerflow studies as described above. Should AIC be unable to complete the proposed transmission line, customer load in the Peoria area would be subjected to continued exposure to possible voltage collapse from the outages discussed above.

Q. **If, as you indicated above, that by summer 2016, the Peoria regional area could experience voltage collapse, why is the in-service date for the proposed project December 1, 2016?**

A. The risk of voltage collapse to the Peoria area does not occur suddenly at a particular load level, but increases over time as load increases. There would be some level of risk currently with the loss of Edwards units 2 and 3 as described above. However, the risk would be more significant by 2014 and greater still in 2015 and 2016. The risk of exposure to voltage collapse was balanced with the feasibility of completing construction in a cost effective manner in determining the project in-service date. Completing any construction project on a highly expedited schedule is usually possible, but it can dramatically increase the cost of construction. Thus, AIC must balance service needs with the costs of accelerating a construction schedule. In other words, AIC must also consider cost effectiveness when determining a project's in-service date.

Q. How will AIC address the potential risk for voltage collapse prior to the project's in service date?

A. Transmission Operations and Distribution Operations groups will take appropriate measures when possible to try to reduce the risk of voltage collapse conditions. These actions include but are not limited to, limiting other work in the area, limiting planned line and generator outages and ensuring system capacitors are available during peak load periods.

V. <u>CONCLUSION</u>

Q. Does this conclude your prepared revised direct testimony?

A. Yes, it does.

APPENDIX

STATEMENT OF QUALIFICATIONS
JAMES L. VERHAAR

I received the Bachelor of Science Degree in Electrical Engineering Technology from Southern Illinois University at Carbondale in May, 1987. I received the Master of Business Administration degree from Aurora (IL) University in December, 2002. I have been a registered professional engineer in the Commonwealth of Pennsylvania since 1993. I was employed at Philadelphia Electric Company and its successor PECO Energy Company as a contract Distribution Engineer from 1988 to 1994. From 1994 to 1997, I was employed at the City of Naperville (IL) Department of Public Utilities-Electric as an Electrical Engineer and a System Controller. From 1997 to 2001, I was employed by ComEd (IL) as a principal Engineer in the Distribution Planning group. I joined Ameren in 2001 as an engineer in the Distribution System Planning Department performing studies related to: designing supplies to major customers, performance and reliable expansion of the subtransmission system and system reactive supply. In 2007, I transferred to the Transmission Planning Group. From 2007 to the present, I have performed various studies regarding Ameren utility and interregional transmission systems, the conceptual design of supplies to major customers and generator interconnection studies.